SIERRA CLUB
FOUNDED 1892

VIA Email and Facsimile

June 26, 2013

Freedom of Information Officer
U.S. EPA Region 9, FOIA Officer OPA-3
75 Hawthorne Street,
San Francisco, CA 94105
Email: r9foia@epa.gov
Facsimile: (415) 947-3591

Re: Freedom of Information Act request -- Hawaiian Commercial & Sugar Company's Pu'unene Sugar Mill, Boiler 3, Maui.

Dear FOIA Officer:

On behalf of the Sierra Club, I am writing to request that the U.S. Environmental Protection Agency ("EPA") provide copies of the records described below pursuant to the Freedom of Information Act, 5 U.S.C. § 552 ("FOIA"), and the EPA regulations at 40 C.F.R. § 2.100, *et seq.* This request is sent to you because you were identified as the proper person to receive such requests. If this request should be directed at another person, please forward this request to that person.

Sierra Club is the nation's oldest grassroots organization. It has more than 1.3 million members and supporters nationwide and 4,100 members in Hawai'i. Sierra Club is dedicated to the protection and preservation of the natural and human environment. Sierra Club's purpose is to explore, enjoy and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; and to educate and enlist humanity to protect and restore the quality of the natural and human environments.

One of Sierra Club's priority national conservation campaigns involves promoting smart energy solutions. Sierra Club is particularly interested in ensuring that coal-fired power plants comply fully with all applicable statutes and regulations. This campaign organizes individuals regionally and nationwide to work on coal-related issues and educates the public on these issues, including the impacts of coal on air and water quality. This FOIA request is made as part of these campaigns.

Documents Requested:[1]

1. All documents related to Hawaiian Commercial & Sugar Company's, hereafter ("HC&S") requests to EPA Region 9[2] for approval of alternative monitoring techniques from 40 CFR Subpart D requirements at HC&S's Pu'unene Sugar Mill, Boiler 3, hereafter ("Pu'unene Boiler 3"), including but not limited to copies of the three original alternative monitoring techniques requests mentioned in Exhibit A at page 2;

2. All attachments and documents related to <u>any</u> requests made by HC&S for alternative monitoring techniques from 40 CFR Subpart D requirements at Pu'unene Boiler 3; and

3. Any and all communications (letters, emails, etc...) between HC&S, EPA, EPA staff, or among EPA, the State of Hawai'i Department of Health, county agencies, local municipalities, or any other third parties which discuss alternative monitoring techniques from 40 CFR Subpart D requirements at Pu'unene Boiler 3.

Exempt Records

Should you decide to invoke a FOIA exemption with regard to any of the requested records, please include in your full or partial denial letter sufficient information for the Sierra Club to appeal the denial. To comply with legal requirements, the following information must be included:

1. Basic factual material about each withheld item, including the originator, date, length, general subject matter, and location of each item; and

2. Explanations and justifications for denial, including the identification of the category within the governing statutory provision under which the document (or portion thereof) was withheld and a full explanation of how each exemption fits the withheld material.

If you determine that portions of a record requested are exempt from disclosure, please redact the exempt portions and provide the remainder of the record to the Sierra Club at the address listed below.

Fee Waiver Request

I respectfully request that you waive all fees in connection with this request as provided

[1] "Records" means information of any kind, including writings (handwritten, typed, electronic or otherwise produced, reproduced or stored), letters, memoranda, correspondence, notes, applications, completed forms, studies, reports, reviews, guidance documents, policies, telephone conversations, telefaxes, e-mails, documents, databases, drawings, graphs, charts, photographs, minutes of meetings, electronic and magnetic recordings of meetings, and any other compilation of data from which information can be obtained. Without limitation, the records requested include records relating to the topics described below at any stage of development, whether proposed, draft, pending, interim, final or otherwise. All of the foregoing are included in this request if they are in the possession of or otherwise under the control of USEPA and all its Offices, Regions and other subdivisions.

[2] Please see Exhibit A attached, HC&S letter to EPA Region 9 Re Request for Approval of Alternative Monitoring of Opacity and Sulfur Dioxide and Request for Determination Regarding Exemption from CEMS Requirement for Monitoring Nitrogen Oxides Under 40 CFR Part 60, Subpart D Puunene Sugar Mill, Boiler 3 (May 15, 2012).

by 5 U.S.C. § 552(a)(4)(A)(iii) and 40 C.F.R. § 2.107(l). The Sierra Club has spent years promoting the public interest through the development of policies that protect human health and the environment, and has routinely received fee waivers under FOIA.

The Sierra Club is a national, nonprofit, environmental organization with no commercial interest in obtaining the requested information. Instead, the Sierra Club intends to use the requested information to inform the public, so the public can meaningfully participate in evaluating EPA's operations and activities related to HC&S' requests for approval of alternative monitoring techniques at Pu'unene Boiler 3.

As explained below, this FOIA request satisfies the factors listed in EPA's governing regulations for waiver or reduction of fees, as well as the requirements of fee waiver under the FOIA statute – that "disclosure of the information is in the public interest because it is likely to contribute significantly to public understanding of the operations or activities of the government and is not primarily in the commercial interest of the requester." 5 U.S.C. § 552(a)(4)(A)(iii); *see also* 40 C.F.R. § 2.107(l).

1. <u>The subject matter of the requested records must specifically concern identifiable "operations and activities of the government."</u>

The requested records relate to EPA's activities regarding HC&S' requests for approval of alternative monitoring techniques at Pu'unene Boiler 3. These activities are "identifiable operations or activities of the government." The Department of Justice Freedom of Information Act Guide expressly concedes that "in most cases records possessed by a federal agency will meet this threshold" of identifiable operations or activities of the government. There can be no question that this is such a case.

2. <u>The disclosure of the requested documents must have an informative value and be "likely to contribute to an understanding of Federal government operations or activities."</u>

The FOIA Guide makes it clear that, in the Department of Justice's view, the "likely to contribute" determination hinges in substantial part on whether the requested documents provide information that is not already in the public domain. The requested records are "likely to contribute" to an understanding of your agency's decisions because they are not otherwise in the public domain and are not accessible other than through a FOIA request. This information will facilitate meaningful public participation in the decision-making process, therefore fulfilling the requirement that the documents requested be "meaningfully informative" and "likely to contribute" to an understanding of your agency's decision-making process with regard to HC&S's requests for approval of alternative monitoring techniques at Pu'unene Boiler 3.

3. <u>The disclosure must contribute to the understanding of the public at large, as opposed to the individual understanding of the requester or a narrow segment of interested persons. Under this factor, the identity and qualifications of the requester—i.e., expertise in the subject area of the request and ability and intention to disseminate the information to the public—is examined.</u>

As described above, the Sierra Club and its members have a longstanding interest and expertise in protecting the environment. More importantly, the Sierra Club unquestionably has the "specialized knowledge" and "ability and intention" to disseminate the information requested in the broad manner, and to do so in a manner that contributes to the understanding of the "public-at-large."

The Sierra Club intends to disseminate the information it receives through FOIA regarding these government operations and activities in a variety of ways, including but not limited to, analysis and distribution to the media, distribution through publication and mailing, posting on the organization's website, emailing and list-serve distribution to members.

4. <u>The disclosure must contribute "significantly" to public understanding of government operations or activities. The public's understanding must be likely to be enhanced by the disclosure to a significant extent.</u>

The records requested will contribute to the public understanding of the government's role, or their "operations and activities" associated with HC&S's requests for approval of alternative monitoring techniques at Pu'unene Boiler 3. The disclosure of the requested records is essential to the public's understanding of EPA's operations and activities. After disclosure of these records, the public understanding of EPA's determinations will be significantly enhanced. The requirement that disclosure must contribute "significantly" to the public understanding is therefore met.

5. <u>Whether the requester has a commercial interest that would be furthered by the requested disclosure.</u>

The Sierra Club has no commercial interest in the requested records. Nor does it have any intention to use these records in any manner that "furthers a commercial, trade, or profit interest" as those terms are commonly understood. The Sierra Club is a tax-exempt organization under sections 501(c)(3) and 501(c)(4) of the Internal Revenue Code, and as such has no commercial interest. The requested records will be used for the furtherance of the Sierra Club's mission to inform the public on matters of vital importance to the environment and public health.

6. <u>Whether the magnitude of the identified commercial interest of the requester is sufficiently large, in comparison with the public interest in disclosure, that disclosure is "primarily in the commercial interest of the requester."</u>

When a commercial interest is found to exist and that interest would be furthered by the requested disclosure, an agency must assess the magnitude of such interest in order to compare it to the "public interest" in disclosure. If no commercial interest exists, an assessment of that non-existent interest is not required.

As noted above, the Sierra Club has no commercial interest in the requested records. Disclosure of this information is not "primarily" in the Sierra Club's commercial interest. On the other hand, it is clear that the disclosure of the information requested is in the public interest. It will contribute significantly to public understanding of EPA's determinations and activities regarding HC&S's requests for approval of alternative monitoring techniques at Pu'unene Boiler 3.

The Sierra Club respectfully requests, because the public will be the primary beneficiary of this requested information, that EPA waive processing and copying fees pursuant to 5 U.S.C. § 552(a)(4)(A). In the event that your agency denies a fee waiver, please send a written explanation for the denial. Also, please continue to produce the records as expeditiously as possible, but in any event no later than the applicable FOIA deadlines.

Record Delivery

In responding to this request, please comply with all relevant deadlines and other obligations set forth in FOIA and the agency's regulations. 5 U.S.C. § 552, (a)(6)(A)(i); 40 C.F.R. § 2.104. Please produce the records above by sending them to me at the address listed below. Please produce them on a rolling basis; at no point should the search for—or deliberation concerning—certain records delay the production of others that the agency has already retrieved and elected to produce.

If possible, please send all documents in PDF format via electronic mail, external website, or on CD or DVD via traditional mail. Alternatively, paper copies are acceptable, but electronic format is preferred. Please send all requested records as soon as possible to:

David Abell
david.abell@sierraclub.org
- or -
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105

Thank you for your cooperation. If you find that this request is unclear in any way please do not hesitate to call me to see if I can clarify the request or otherwise expedite and simplify your efforts to comply. I can be reached at 415.977.5764 or by e-mail at david.abell@sierraclub.org.

David Abell
Sierra Club Environmental Law Program

Exhibit A

HDOH COPY MAY 18 2012

A&B, INC.
HONOLULU

TELEPHONE: (808) 877-2959
FACSIMILE: (808) 871-7663

CN

HAWAIIAN COMMERCIAL & SUGAR COMPANY

P.O. BOX 266, PUUNENE, MAUI, HAWAII 96784

POSTMARKED MAY 16 2012 DATE

May 15, 2012

Ms. Deborah Jordan
Director, Air Division
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, CA 94105

Engineering may want to see.

Attention: Mr. Steve Frey

Subject: Request for Approval of Alternative Monitoring of Opacity and Sulfur Dioxide and Request for Determination Regarding Exemption from CEMS Requirement for Monitoring Nitrogen Oxides Under 40 CFR Part 60, Subpart D Puunene Sugar Mill, Boiler 3

Dear Ms. Jordan:

Hawaiian Commercial and Sugar Company (HC&S) operates three multi-fueled boilers at its Puunene Sugar Mill on the island of Maui, Hawaii. In August 2001, HC&S determined that Puunene Mill Boiler 3 may be subject to New Source Performance Standards (NSPS) under 40 CFR Part 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971. Boiler 3 is a multi-fueled boiler which fires primarily renewable sugarcane bagasse (the fibrous biomass material produced by milling sugarcane). On average, bagasse accounts for 70 to 80 percent of the annual heat input to Boiler 3, and the facility's existing air pollution control permit requires that the annual heat input from biomass fuels must exceed 50 percent of the total annual heat input to this boiler. Boiler 3 also fires low-sulfur bituminous coal (coal consumption is further limited to 45,000 tons per year) and fuel oil (diesel fuel and specification used oil fuel, typically accounting for no more than three percent of the annual heat input to the boiler).

The boiler was originally permitted in 1973, and at that time (and at various times thereafter) it had been determined by the permitting authority that this boiler was *not* subject to Subpart D. Rather, by virtue of the fact that it combusted primarily sugarcane bagasse, a non-fossil fuel, both HC&S and the Hawaii Department of Health (HDOH) Clean Air Branch believed Boiler 3 to be classified as a non-fossil-fuel-fired boiler (see Attachment 1). When in 2001 HC&S identified EPA guidance suggesting that Boiler 3 should in fact be considered a fossil-fuel-fired boiler, HC&S notified HDOH and developed and implemented a plan to bring the boiler into compliance with the applicable NSPS.

C2012-08CEMS/COMS

HDOH COPY

MD 19570

This letter reiterates three earlier requests made to EPA Region 9 and to HDOH for approval of alternative monitoring techniques:

- Approval of alternative monitoring of opacity in lieu of installation of a COMS on the Boiler 3 stack (per 40 CFR §60.13(i)(1));
- Approval of alternative monitoring of sulfur dioxide (SO_2) emissions in lieu of installing a continuous emissions monitoring system (CEMS) for SO2 on the Boiler 3 stack (per 40 CFR §60.45(b)(2)); and
- Concurrence by EPA Region 9 that a CEMS for monitoring of emissions of nitrogen oxides (NO_x) is not required to be installed on the Boiler 3 stack (per 40 CFR §60.45(b)(3)).

Each of these requests, and the basis for each request, is restated below.

Continuous Opacity Monitoring Under Subpart D

Under §60.45 of Subpart D, a continuous opacity monitoring system (COMS) is required for measuring the opacity of emissions from affected sources. The Boiler 3 stack is equipped with a venturi wet scrubber for particulate matter control. Because water vapor in the exhaust gas exiting the wet scrubber would interfere with operation of a COMS, HC&S in March 2002 submitted to the EPA Region 9 Air Division Director a request for approval of alternative monitoring of opacity under 40 CFR §60.13(i)(1) (Attachment 2). Under the proposed alternative monitoring procedure, which was modeled after alternative monitoring procedures previously approved by EPA for other sources with wet scrubbers, HC&S was to continuously monitor and record the Boiler 3 wet scrubber liquid flow rate and the pressure drop of the gas stream across the scrubber venturi, and to maintain these parameters within specified limits. HC&S was also to conduct a monthly visual emissions evaluation of the Boiler 3 stack in accordance with Method 9 of 40 CFR Part 60, and to submit semiannual reports of excess emissions, as defined in the procedure, to the HDOH Clean Air Branch.

In order to ensure compliance with the opacity monitoring requirement under Subpart D while awaiting approval of the alternative monitoring procedure by EPA, HC&S installed instrumentation on the Boiler 3 wet scrubber so that the relevant wet scrubber operating parameters could be continuously monitored and recorded, and HC&S has implemented the proposed alternative opacity monitoring procedure since 2003. HC&S subsequently modified the proposed procedure as necessary to address operation of the Boiler 3 wet scrubber in both "once-through" and recirculation modes.[1] Updated versions of the proposed procedure were provided to HDOH in various compliance progress reports and permit applications since its implementation.

[1] In "once-through" mode, the water supplied to the wet scrubber is used once and is then discharged into the facility's wastewater irrigation system and used to irrigate a portion of the sugarcane crop. In recirculation mode, water supplied to the wet scrubber is recycled back to the wet scrubber and reused in order to reduce the amount of wastewater generated, and a portion of the scrubber water is continuously discharged to maintain the solids content of the scrubbing liquid within desired limits.

HC&S has been adhering to its proposed alternative opacity monitoring procedure in lieu of installing a COMS since it was implemented in February 2003. However, the procedure has not yet been formally approved by EPA or HDOH.

Request for Approval of Alternative Monitoring of Opacity

HC&S hereby reiterates its earlier request for approval of alternative monitoring of opacity of the Boiler 3 stack. In lieu of installing a COMS on the Boiler 3 stack, HC&S proposes to adhere to the attached *Procedure for Meeting Alternative Opacity Monitoring, Notification, and Recordkeeping Requirements – Puunene Mill Boiler 3* (Attachment 3). As noted above, a COMS installed on the Boiler 3 stack would not provide accurate measurement of opacity due interferences caused by liquid water and water vapor in the effluent gases. Accordingly, alternative monitoring is appropriate pursuant to 40 CFR §60.13(i)(1).

HC&S proposes to monitor and record operating parameters of the Boiler 3 wet scrubber (specifically, water flow and venturi differential pressure) and to maintain these parameters within specified ranges. Proposed wet scrubber operating ranges are based upon average wet scrubber flows and differential pressures recorded during stack testing demonstrating compliance with applicable emission limits or, where test data is not available, on the wet scrubber manufacturer's recommended operating range. Similar alternative monitoring procedures have been approved by EPA for Subpart D sources which use a wet scrubber for particulate matter control. See U.S. EPA Applicability Determination Index Control Numbers 0000010 (Attachment 4) and 0500093 (Attachment 5).

Approval of alternate monitoring of opacity in lieu of installing a COMS for monitoring visible emissions is appropriate for the following reasons:

(1) The Boiler 3 stack is equipped with a venturi wet scrubber for particulate matter control, and water vapor in the exhaust gas exiting the wet scrubber would therefore interfere with operation of a COMS.
(2) Section 60.13(i)(1) allows the Administrator to approve alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by 40 CFR Part 60 would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.
(3) Procedures for alternative monitoring of opacity similar to that proposed by HC&S have been approved by EPA for other Subpart D sources with wet scrubbers.

Monitoring of Sulfur Dioxide Emissions Under Subpart D

Under §60.45 of Subpart D, a continuous emissions monitoring system (CEMS) is required for monitoring SO_2 emissions from affected sources. However, §60.45(b)(2) provides that for a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

Sulfur dioxide emissions from Boiler 3 are controlled through limitations on the sulfur content of all permitted fuels. Under state air pollution control rules, all fossil fuels fired in Boiler 3 are limited to a maximum sulfur content of 0.5 percent by weight, and the existing operating permit for Boiler 3 requires that only low sulfur coal with a maximum sulfur content of 0.5 percent by weight may be fired.[2] Although the wet scrubber is capable of reducing sulfur dioxide emissions from Boiler 3 by a nominal amount, it was installed for the sole purpose of controlling particulate matter emissions; it is not operated as a flue gas desulfurization device for the purposes of compliance with Subpart D emission limits. Existing limitations on fuel sulfur content alone are sufficient to ensure compliance with the Subpart D limits on SO_2 emissions for solid (1.2 lb/MMBTU) and liquid (0.8 lb/MMBTU) fossil fuels[3].

In October 2001, HC&S developed and implemented interim fuel sampling and analysis procedures for both coal and fuel oil to be used to monitor emissions of SO_2 from the Boiler 3 stack until such time as either a CEMS for SO_2 was installed or was determined not to be required. Between 2001 and 2003, HC&S had various discussions with both HDOH and EPA regarding fuel sampling and analysis (FSA) as an alternative to installing a CEMS on the Boiler 3 stack for monitoring of emissions of SO_2. Although HDOH had initially rejected alternative monitoring of SO_2, based on further discussions and additional information provided by HC&S both HDOH and EPA agreed to reconsider this option and in April 2003 HC&S submitted to HDOH (with a copy to EPA) a request for approval of alternatives to CEMS requirements for Boiler 3 (Attachment 6). HDOH subsequently forwarded this request to the EPA Region 9 Air Division Director with a request for a determination (Attachment 7).

HC&S has been adhering to its interim fuel sampling and analysis plan for coal and its proposed FSA for fuel oil in lieu of installing a CEMS for monitoring SO2 since these plans were originally developed and implemented in 2001. Because the proposed FSA plan for coal submitted to HDOH and EPA in 2003 would require a significant capital outlay for coal sampling and sample preparation equipment, HC&S has continued to rely on its interim FSA plan for coal pending approval of the FSA program by EPA. The FSA plans for coal and fuel oil have not yet been approved by HDOH or EPA.

Request for Approval of Alternative Monitoring of Sulfur Dioxide Emissions

HC&S hereby reiterates its earlier request for approval of alternative monitoring of SO_2 emissions from the Boiler 3 stack. In lieu of installing a CEMS for SO2 on the Boiler 3 stack, HC&S

---

[2] The coal fired in the Boiler 3 is classified as "compliance coal" because it emits less than 1.2 lb/MMBTU of sulfur dioxide when burned.

[3] Since 1992, the heat value of bituminous coal burned in Boiler 3 has ranged from 11,118 BTU/lb to 12,747 BTU/lb. At the lowest measured heat value and the maximum coal sulfur content of 0.5 percent sulfur by weight, this equates to maximum *uncontrolled* SO_2 emissions of 0.9 lb/MMBTU, or 75 percent of the Subpart D emission limit (assuming 100 percent conversion of sulfur to SO_2). Fuel oil no. 2 (diesel fuel) has a typical heat content of 19,300 BTU/lb. At the maximum fuel oil sulfur content of 0.5 percent sulfur by weight, this equates to maximum *uncontrolled* SO_2 emissions of 0.52 lb/MMBTU, or about 65 percent of the Subpart D emission limit. Specification used oil has a heat content comparable to that of diesel fuel and so would have similar uncontrolled SO_2 emissions at 0.5 percent sulfur by weight.

proposes to adhere to the attached *Fuel Sampling and Analysis Procedures – Fuel Oil (Rev. September 2007)* (Attachment 8) and *Proposed Fuel Sampling and Analysis Procedures – Coal (Rev. July 2005)* (Attachment 9).

Fuel Sampling and Analysis for Fuel Oil

The proposed FSA for fuel oil is based on procedures contained in Section 2.2 of 40 CFR Part 75, Appendix D, *Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units*. For diesel fuel (fuel oil no. 2), the FSA procedure requires fuel samples to be obtained from each fuel tanker delivered to HC&S, or from each fuel lot (i.e., barge load) delivered to the fuel supplier's storage tanks, and to be analyzed for sulfur content and gross calorific value (GCV). For specification used oil fuel[4], the FSA procedure requires that fuel samples representative of each tanker load of commercial specification used oil fuel delivered to HC&S and samples representative of all in-house used oil are to be analyzed for sulfur content and GCV. Results of these analyses for all fuel oil fired in Boiler 3 are to be used to calculate maximum uncontrolled SO_2 emissions, which are then to be compared to the Subpart D emission limit. The plan also requires semi-annual reporting of monitoring results.

Approval of the FSA for fuel oil as an alternative to installing a CEMS for monitoring SO_2 emissions is appropriate for the following reasons:

(1) Subpart D §60.45(b)(2) specifically provides that a CEMS for monitoring of SO_2 emissions is not required if SO_2 emissions are monitored by fuel sampling and analysis.

(2) Although no fuel sampling and analysis procedure for fuel oil has been specified in §60.45(b), §60.13(i) allows the Administrator to approve alternatives to any monitoring procedures or requirements of 40 CFR Part 60.

(3) EPA has previously approved FSA programs for oil-fired units based upon the oil sampling and analysis procedures contained in 40 CFR Part 75, Appendix D. See for example U.S. EPA Applicability Determination Index Control Number 9600010 (Attachment 4).

(4) Variations in fuel sulfur content and GCV within a given lot of fuel oil are expected to be negligible, given the relative homogeneity of fuel oil and the representative sampling methods employed. The proposed sampling of each tanker load of fuel delivered to HC&S, or of each fuel lot (i.e., barge load) delivered to the fuel supplier, will therefore

---

[4] The HC&S *Fuel Sampling and Analysis Procedures – Fuel Oil* was revised in 2005 to incorporate sampling and analysis of specification used oil fuel based upon the HDOH position that used oil is regulated as a fossil fuel under the NSPS. Past guidance from EPA headquarters, however, indicates that EPA does not consider "waste lubricating oils" (i.e., used oil) that are burned in a stream generator to constitute "fossil fuel". See EPA Applicability Index Control Number D100 (Attachment 17), which states in relevant part, "Waste lubricating oils are not considered fossil fuels because their purpose is not the creation of useful heat, but rather for use as a lubricant. Even though these waste oils will undergo minor filtering to remove dirt and water, and will then be consumed in a boiler, they are still not considered fossil fuels as defined in 40 CFR 60.41(b)". HC&S intends to continue to monitor specification used oil fuel fired in Boiler 3 until such time as HDOH advises that it concurs with EPA's interpretation. In that event, HC&S proposes to revise the FSA procedure for fuel oil to delete requirements applicable to specification used oil, since Subpart D emission limits apply only to emissions from firing fossil fuels and wood residue.

ensure results are sufficiently representative of all fuel oil fired to allow comparison to the applicable SO_2 emission limit.

(5) The existing limit on the sulfur content of fuel oil fired in Boiler 3 is sufficient to ensure that SO_2 emissions during fuel oil firing will be below the emission limit specified in §60.43(a)(1) by a substantial margin. Maximum uncontrolled emissions from firing fuel oil no. 2 (or specification used oil) with a sulfur content of 0.5 percent by weight are approximately 65 percent of the applicable emission limit.

(6) Due to the phase-in of regulations requiring the use of low sulfur diesel fuel/ultra low sulfur diesel fuel in mobile sources and non-road engines, the fuel oil no. 2 currently available on the island of Maui has a sulfur content of 500 parts per million or less. The highest sulfur content reported for fuel oil burned in Boiler 3 since February 2006 has been 424 ppm (0.04 percent by weight), and the highest sulfur content reported for fuel oil burned in Boiler 3 in 2010 and 2011 has been 8 ppm (0.0008 percent by weight). Actual uncontrolled emissions of SO_2 from burning this fuel are therefore at least an order of magnitude lower than would be achieved by burning this fuel at the maximum sulfur content of 0.5 percent. Indeed, the highest SO_2 emission rate calculated since February 2006 for fuel oil no. 2 burned in Boiler 3 (based on the sulfur content and GCV of any single fuel lot) has been 0.04 lb/MMBTU, just five percent of the Subpart D emission limit.[5]

(7) The wet scrubber is required to be in operation at all times when Boiler 3 is in operation. Although not operated as a flue gas desulfurization device, a degree of sulfur dioxide control is achieved by the wet scrubber incidental to its use for particulate matter control. Emissions of SO_2 from the Boiler 3 stack when firing fuel oil are therefore even lower than the emissions calculated based on fuel sulfur content and GCV would indicate. While HC&S is not suggesting that incidental SO_2 removal by the wet scrubber should be factored into compliance determinations under the proposed FSA program, operation of the wet scrubber nevertheless does provide an added assurance that the compliance margins already inherent in the permitted fuel sulfur limit and the proposed sampling methodology will be adequate to ensure compliance with the Subpart D emission limit at all times during fuel oil firing.

Fuel Sampling and Analysis for Coal

The proposed FSA program for coal is based on procedures contained in Method 19, *Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates*, found in 40 CFR Part 60, Appendix A. For coal, the FSA procedure requires fuel samples to be obtained from each fuel lot burned in Boiler 3, using ASTM sampling methods and systematic spacing, and to be analyzed for sulfur content and gross calorific value (GCV). Results of these analyses for all coal fired in Boiler 3 are to be used to

[5] For specification used oil fuel, calculated SO_2 emission rates on the order of 0.5 lb/MMBTU heat input remain typical, since used oil combusted in boilers is not subject to the diesel fuel sulfur phase-out. As noted previously, however, this still provides a substantial compliance margin relative to the Subpart D emission limit for SO_2 when firing fuel oil. Moreover, since EPA has stated that it does not consider used oil to be a "fossil fuel" as the term is defined in the NSPS, HC&S does not anticipate it will need to continue to demonstrate compliance with Subpart D emission limits when firing this fuel.

calculate maximum uncontrolled SO_2 emissions, which are then to be compared to the Subpart D emission limit. The plan also requires semi-annual reporting of monitoring results. To obtain the requisite samples, HC&S has proposed to install sampling equipment on the coal belt that would automatically obtain samples in accordance with ASTM protocols. The samples would then be reduced and prepared in an on-site lab, again in conformance with applicable ASTM methods, and shipped to a fuels laboratory for analysis.

Approval of the proposed FSA program for coal as an alternative to installing a CEMS for monitoring SO_2 emissions is appropriate for the following reasons:

(1) Subpart D §60.45(b)(2) specifically provides that a CEMS for monitoring of SO_2 emissions is not required if SO_2 emissions are monitored by fuel sampling and analysis.

(2) Although no fuel sampling and analysis procedure for coal has been specified in §60.45(b), §60.13(i) allows the Administrator to approve alternatives to any monitoring procedures or requirements of 40 CFR Part 60.

(3) EPA has previously approved FSA programs for coal-fired units based upon the coal sampling and analysis procedures contained in Method 19 of 40 CFR Part 60, Appendix A. See for example U.S. EPA Applicability Determination Index Control Numbers NR35 (Attachment 11) and 9800058 (Attachment 12). It is our understanding based on ADI Control Number NR35 that at least twelve Subpart D sources in EPA Region 5 have been approved to use FSA for SO_2 emissions monitoring.

(4) EPA in 2006 revised §60.43 so that owners or operators of affected sources may petition the Administrator to allow compliance with §60.42b(k) of 40 CFR Part 60, Subpart Db as an alternative to meeting the requirements of §60.43(a) and (b). Under §60.42b(k)(3), units (such as Boiler 3) that are located in a non-continental area must not discharge any gases that contain SO_2 in excess of 1.2 lb/MMBTU heat input when combusting coal or 0.5 lb/MMBTU heat input when combusting oil.[6] The numerical emission limit for non-continental sources firing coal under §60.42b(k)(3) is identical to that specified for coal firing under §60.43(a). However, compliance with the Subpart Db limit is determined differently (i.e., according to §60.47b) than is compliance with the Subpart D limit. Specifically, §60.47b(b) allows the owner or operator of an affected source, as an alternative to CEMS, to determine the average SO_2 emissions *by collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of Appendix A to Part 60.* Compliance with the numerical emission limit is then based on the 30-day average of the calculated daily emission rates. Thus, coal-fired sources located in non-continental areas that are subject to the SO_2 emission limit in Subpart D may, subject to Administrator approval, elect to instead comply with the same numerical emission limit (1.2 lb/MMBTU of hear input) but to determine compliance based on a longer (i.e., 30-day) averaging period. That is, EPA has determined, through rulemaking, that certain coal-fired sources (i.e., those, such as Boiler 3, located in non-continental areas) may (again, subject to Administrator approval) comply with the numerical SO_2 emission limit specified in

[6] For units located in a non-continental area, only emission limits are specified under §60.42b(k)(3). These units are not subject to any standard for percent reduction of the potential SO_2 emission rate.

Subpart D using a longer averaging period than that specified in Subpart D, and that Method 19 is the appropriate method to be used for determining compliance. At this time, HC&S is *not* requesting approval to comply with §60.42b(k) instead of §60.43(a) and (b) (though we may elect to do so depending upon the outcome of our current request). Rather, we are merely pointing out that approval of a FSA program under Subpart D that is based on Method 19 and that employs an alternative lot size is not only consistent with past EPA approvals of coal FSA programs, but is also consistent with existing compliance options EPA has directly incorporated into the Subpart D regulations.[7]

(5) The existing requirement to burn only low-sulfur coal in Boiler 3, in and of itself, is sufficient to provide a high degree of assurance that SO_2 emissions during coal firing will be below the limit specified in §60.43(a)(1), even considering the normal variations in fuel sulfur content typical of coal. Specifically:

- Maximum uncontrolled emissions from firing coal with a sulfur content of 0.5 percent by weight are just 75 percent of the applicable Subpart D emission limit, and the highest uncontrolled SO_2 emission rate actually calculated since 1992 for any coal delivery to HC&S (based on the sulfur content and GCV of the delivery) has been 0.87 lb/MMBTU, or 72 percent of the Subpart D emission limit.
- In order for maximum SO_2 emissions Boiler 3 to exceed the Subpart D emission limit during coal firing, the sulfur content of the coal being fired would have to exceed the existing permit limit of 0.5 percent sulfur by weight by at least 33 percent.[8] HC&S believes that this degree of variability in the sulfur content of the coal it combusts is unlikely based on past coal analyses, including analysis of dozens of coal samples obtained over one-hour averaging periods during annual stack testing.
- HC&S is located on an island with limited options for coal supplies. Coal is delivered by ship two to three times per year, and is provided by a very limited number of suppliers. Since 2001, HC&S has received nearly 90 percent of its coal from a single mine and has received all of its coal from just two mines. HC&S is therefore not subject to the potentially greater variability in coal supplies that might be experienced by mainland facilities capable of obtaining coal from multiple sources via rail. Moreover, HC&S burns a relatively small amount of coal in its boilers each year (approximately 60,000 tons per year in all three boilers combined, and approximately 35,000 tons in Boiler 3), further reducing the expected variability in supplies.

(6) The wet scrubber is required to be in operation at all times when Boiler 3 is in operation. Although not operated as a flue gas desulfurization device, sulfur dioxide removal is achieved by the wet scrubber incidental to its use for particulate matter control.[9]

---

[7] The coal FSA program proposed by HC&S incorporates the equivalent of the 24-hour averaging period allowed under other coal FSA programs that have been approved under Subpart D. See further discussion below.

[8] This value (0.67 percent sulfur) was calculated using the lowest heat content measured for any coal delivery to HC&S since 1992 and assuming 100 percent conversion of sulfur to SO_2.

[9] When operated in "once-through" mode as originally designed, the Boiler 3 wet scrubber provides incidental control of SO_2 emissions such that actual SO_2 emissions during coal firing are on the order of 60 percent lower than the maximum uncontrolled SO_2 emissions. When the wet scrubber is operated in recirculation mode, actual SO_2 emissions during coal firing can be on the order of 15 percent lower than the

Emissions of SO_2 from the Boiler 3 stack when firing coal are therefore substantially less than the uncontrolled emissions calculated based on fuel sulfur content and GCV. While HC&S is not suggesting that incidental SO_2 removal by the wet scrubber should be factored into compliance determinations under the proposed FSA program, operation of the wet scrubber nevertheless does provide an added assurance that the compliance margins already inherent in the permitted fuel sulfur limit and in the proposed sampling methodology will be adequate to ensure compliance with the Subpart D emission limit at all times during coal firing.

(7) Operation of a CEMS on a multi-fuel boiler which burns both fossil fuels and non-fossil fuels is inherently complex and is likely to lead to erroneous compliance determinations when a fuel of highly variable quality such as bagasse is being fired. This is in part due to the fact that, whereas the CEMS will measure emissions produced by *all* fuels being fired at any given time, only that portion of the measured emissions that is from firing fossil fuels (and wood residue) is subject to the Subpart D emission limits.[10] Further, only the heat input from firing fossil fuels (and wood residue) may be considered when determining compliance with emission limits in lb/MMBTU of heat input. Thus, when bagasse is fired in combination with coal, for example, it is necessary to determine what fraction of the emissions measured by the CEMS resulted from the coal and what fraction resulted from the bagasse.[11] This requires accurate measurements of the bagasse (and other fuel) feed and heat input rates and the use of certain assumptions regarding emission rates from firing bagasse. In addition, the calculation of emission rates by the CEMS requires the use of an "F-factor"; for facilities firing fuels in combination, the F-factor to be used in the calculation is determined based on the F-factor for each individual fuel being fired and the fraction of the total heat input being derived from each fuel. Due to the highly variable nature of bagasse[12], both the determination of the heat input from bagasse and the use of a

---

maximum uncontrolled SO_2 emissions due to re-use of the scrubber water. During operation in recirculation mode, however, the pH of the scrubber water is normally maintained at the same neutral pH as in once-though mode, resulting in equivalent emissions of SO_2 in either operating mode. No reduction in SO_2 emissions by the wet scrubber is required in order to comply with the Subpart D emission limit during coal or fuel oil firing.

[10] Unlike emission limits in Subparts Da and Db which apply to emissions from *all* fuels being fired in an affected facility, all Subpart D emission limits are presented in terms of pounds of pollutant per million BTU of heat input ***derived from fossil fuel or fossil fuel and wood residue***.

[11] Although the sulfur content of bagasse is relatively low, this fuel does contain some sulfur (typically on the order of 0.05 percent by weight, as fired). Thus, when co-firing bagasse with coal at a 5:1 ratio (a typical operating scenario), uncontrolled SO_2 emissions generated by the bagasse (in lb/hr) may actually exceed those generated by the coal. If SO_2 emissions from the bagasse were not quantified and subtracted from the total SO_2 emissions measured by the CEMS, then the SO_2 emission rate attributed to the coal could be more than double the true emission rate. This variance will be even greater as the ratio of bagasse to coal is increased. A similar, but even greater, concern exists with respect to using CEMS to monitor NO_x emissions from a bagasse-fired boiler, as discussed in more detail below.

[12] Bagasse is fired in sugar mill boilers "as produced" in the mill. Thus, the quality of the fuel being burned at any given time is highly dependent upon multiple factors, including field harvesting conditions, mill operations, the cane variety, and growing conditions experienced by the crop. As a result, bagasse moisture and "as-fired" heat content can fluctuate over a wide range. Similarly, variations in the fuel make it very

"default" F-factor are highly problematic and may contribute to significant errors in the resulting emissions calculations and compliance determinations. Compared to the use of CEMS on a multi-fueled boiler, particularly one which fires bagasse, under Subpart D the use of FSA for monitoring of SO_2 emissions is far less complex, requires the accurate measurement of far fewer parameters, and is far more likely to provide a reliable determination regarding compliance with applicable emission limits.

Justification for Alternative Lot Size Under the Proposed Fuel Sampling and Analysis for Coal

During the sugarcane grinding season (typically, nine months out of each year), Boiler 3 combusts primarily sugarcane bagasse; coal is fired as a "trim fuel" to maintain good combustion when bagasse quality fluctuates (e.g., due to increased moisture content), or when the supply of bagasse to the boilers is interrupted due to equipment failure, temporary mill shutdown, or similar circumstances. The quantity of coal fired in Boiler 3 during any 24-hour period of the grinding season can therefore vary significantly, from no coal at all or just a few tons to on the order of 450 tons.[13] During the non-grinding season (typically, three months out of each year), bagasse is not available and the Puunene Mill boilers burn primarily coal in order to continue to generate electricity for use on the plantation and by the electric utility. Boiler 3 is typically shut down for maintenance and repairs during approximately one month of the off-season. During the remainder of the off-season, Boiler 3 coal consumption will vary depending upon power needs on the plantation (e.g., for running irrigation pumps) and by the utility, but will generally be well below the boiler's rated capacity on coal.[14]

Under Method 19, the "lot size" for a coal FSA program is "typically" the weight of coal burned in a one-day (24-hour) period. However, Method 19 provides that "alternative definitions of lot sizes may be used, subject to prior approval of the Administrator". Method 19 also requires coal samples to be collected using ASTM Method D 2234, *Standard Practice for Collection of a Gross Sample of Coal*, based on systematic spacing (i.e., evenly spaced increments in time or increments based on equal weights of coal passing the sample collection area). Under the ASTM standard, a pre-determined number and size of sample increments must be collected into a gross sample that is representative of the "lot" of coal being sampled. Unlike coal-fired utility boilers that normally fire coal exclusively and at relatively constant rates over long periods of time, the highly variable coal consumption rates in Boiler 3 make it impracticable to obtain a representative coal sample using time-based increments.[15] Thus, in its FSA program for coal, HC&S proposed an alternative

difficult to assign a default "F-factor" for use in the calculation of emission rates. All of these factors may contribute to errors when calculating emission rates from bagasse firing using default assumptions.

[13] Boiler 3 is rated at 437 MMBTU/hr heat input on coal. At a typical heat content of approximately 23 MMBTU/ton for the bituminous coal fired at HC&S, this equates to a maximum coal firing rate of 456 tons/day when the boiler is operated at full load on 100 percent coal.

[14] At its permitted coal consumption limit (45,000 tons per year), Boiler 3 would burn *on average* approximately 135 tons of coal per day of boiler operation (assuming the boiler operates every day of the year except during the annual maintenance outage). Combined coal consumption in all three Puunene Mill boilers averages approximately 178 tons per day of boiler operation.

[15] For example, when sampling during a day when very little coal is fired in Boiler 3, time-based sample increments might be obtained from the coal belt when no coal is actually being fired in any of the boilers. Similarly, if time-based sample increments were obtained only when coal was actually being fired, the

lot size based on the maximum quantity of coal that could be consumed in Boiler 3 during a steam generating unit operating day (i.e., approximately 450 tons). That is, coal would be sampled systematically using weight-based increments so that a single representative sample would be obtained for every 450 tons of coal fired in the Puunene Mill boilers. HC&S believes that this lot size is appropriate for sampling coal fired in Boiler 3 for the following reasons:

(1) Due to the intermittent nature of coal firing during the majority of the year, systematic spacing of coal samples using time-based increments is not practical, and would not generate representative samples. It is therefore necessary to use weight-based increments in order to achieve systematic spacing of coal samples as required by the ASTM method. That is, a sample increment must be obtained each time a set amount of coal passes over the coal scale.

(2) The proposed lot size meets the intent of Method 19 because it corresponds to the amount of coal that could be burned in Boiler 3 during a 24-hour period. During any day when Boiler 3 is operated at rated capacity on 100 percent coal, this lot size would equal the amount of coal actually fired during that 24-hour period. Under Method 19, it is accepted that this lot size will adequately reflect the variability of coal fired during that 24-hour period. There would therefore appear to be little justification for further decreasing the lot size during days when a lesser amount of coal is fired, particularly considering the difficulties in sampling coal fired by this source using a time-based sample increment.

(3) The proposed lot size is already far smaller than the lot size that would typically be approved under a FSA program for the vast majority of Subpart D sources and is therefore far more likely to capture variations in coal sulfur content. While the ability to reflect variability in coal sulfur content would theoretically continue to improve as the lot size approaches zero, at some point the additional precision is neither necessary for providing an acceptable assurance of compliance nor reasonable from a cost standpoint. Given the much larger lot size that would typically be employed by other Subpart D sources under Method 19, HC&S believes strongly that the use of a lot size less than 450 tons is unwarranted and would result in an insignificant incremental improvement in the ability to capture variations in coal sulfur content. The vast majority of coal-fired Subpart D sources in the United States appear to be electric utility boilers that are considerably larger than Puunene Mill Boiler 3.[16] On average, the rated capacity of these boilers is over ten times the rated capacity of Boiler 3, and nearly 90 percent of these boilers have a rated capacity at least five times that of Boiler 3. These boilers typically operate year-round on coal at

number of sample increments obtained during days of low coal consumption could be insufficient to comprise a representative sample under the ASTM standard.

[16] A 1984 EPA survey determined that at that time there were 140 Subpart D boilers operating at 99 power plants in the United States. While it is unclear whether the survey included Subpart D boilers located at industrial facilities, at minimum the survey encompasses a significant cross-section of Subpart D sources. On average, the rated capacity of these units was reported to be approximately 480 MW electric (MWe), equivalent to a boiler heat input capacity of over 5,200 MMBTU/hr, or more than eleven times the rated capacity of Boiler 3. Nearly 90 percent of these boilers had a rated capacity of 213 MWe, equivalent to a boiler heat input capacity of over 2,300 MMBTU/hr, or five times the rated capacity of Boiler 3. Only one unit had a rated capacity less than that of Boiler 3, and only three units had rated capacities less than twice that of Boiler 3.

comparatively high utilization rates, while Boiler 3 is fired primarily on non-fossil fuel (coal comprising, on average, no more than 20 to 30 percent of the annual heat input to the boiler). It is therefore expected that the amount of coal fired in a typical Subpart D boiler during any operating day will be many times the amount of coal fired in Boiler 3 during the same time period.[17] On this basis, HC&S believes that the already comparatively small lot size proposed in its FSA program (450 tons) will provide an indication of coal sulfur variability that is equivalent to or better than that provided by the much larger lot sizes that could be used by the majority of Subpart D sources employing FSA to demonstrate compliance with the SO_2 emission limit.[18]

(4) Section 60.43 now allows compliance with §60.42b(k) of 40 CFR Part 60, Subpart Db as an alternative to meeting the requirements of §60.43(a) and (b), with approval from the Administrator. Under this alternative, compliance is based on a 30-day average of measured daily SO_2 emissions rates. This amounts to determining compliance based on the amount of coal burned during a 30-day period, which for Boiler 3 corresponds to an amount of coal significantly greater than 450 tons. While HC&S is *not* requesting approval to comply with §60.42b(k) at this time, clearly approval of the proposed alternative lot size is consistent with, and in fact more restrictive than, existing compliance options EPA has directly incorporated into the Subpart D regulations.

Monitoring of Nitrogen Oxides Emissions Under Subpart D

Under §60.45 of Subpart D, a continuous emissions monitoring system (CEMS) is required for monitoring NO_x emissions from affected sources. However, §60.45(b)(3) provides that if an owner or operator demonstrates during performance testing that emissions of NO_x are less than 70 percent of the applicable standards in §60.44, a CEMS for measuring NO_x emissions is not required.

In September 2001, HC&S completed performance testing of Boiler 3 on coal demonstrating that emissions of NO_x during coal firing were less than 70 percent of the applicable standard in §60.44. During that same month, HC&S completed performance testing of Boiler 3 on low sulfur fuel oil no. 6 (LSFO) in an attempt to demonstrate that the boiler could comply with Subpart D emission limits when firing this fuel.[19] Since test results indicated that the boiler did not comply with all Subpart D emission limits when firing LSFO, HC&S abandoned plans to burn this fuel in Boiler 3 and began firing diesel fuel to ensure compliance with Subpart D. Subsequently, in October 2002, HC&S completed performance testing on diesel fuel demonstrating that emissions of NO_x during firing of this fuel were less than 70 percent of the applicable standard in §60.44. Since these initial tests, HC&S completed annual stack tests of Boiler 3 on coal each year from 2002 to 2011 and also completed testing of Boiler 3 on diesel fuel in 2003, 2004, and 2005. In

[17] In fact, of the 140 Subpart D units identified in the 1984 EPA survey, nearly 90 percent had the capacity to fire as much coal in a single hour as Boiler 3 fires during an average operating day.

[18] A lot size under Method 19 that is based on the amount of coal fired during an operating day could include up to 2,400 tons of coal for nearly 90 percent of the coal-fired units identified in the 1984 survey.

[19] Prior to the 2001 stack test, HC&S had never fired LSFO in Boiler 3. It was hoped that firing this fuel in place of the high sulfur fuel oil that had previously been fired in Boiler 3 would ensure compliance with Subpart D emission limits.

addition, HC&S completed testing of Boiler 3 on specification used oil in 2010. None of these performance tests showed NO_x emissions to be greater than 70 percent of the applicable standard.

On the basis of the performance test results, HC&S concluded that installation of a CEMS on the Boiler 3 stack for monitoring emissions of NO_x was not required, pursuant to §60.45(b)(3) and advised the permitting authority accordingly.[20] Although HDOH initially disagreed with this determination, based on further discussions and additional information provided by HC&S both HDOH and EPA agreed to reconsider this option and in April 2003 HC&S submitted to HDOH (with a copy to EPA) a request for approval of alternatives to CEMS requirements for Boiler 3 (Attachment 13). HDOH subsequently forwarded this request to the EPA Region 9 Air Division Director with a request for a determination. EPA has not yet provided a final determination.

Request for a Determination That a CEMS Is Not Required for Monitoring of Nitrogen Oxides Emissions

HC&S hereby reiterates its earlier request for concurrence with its determination, made based on results of stack testing, that installation of a CEMS for monitoring NO_x emissions from Boiler 3 is not required.

Concurrence with the determination that CEMS is not required for monitoring NO_x emissions is appropriate for the following reasons:

(1) Subpart D §60.45(b)(3) specifically provides that a CEMS for monitoring of NO_x emissions is not required if the owner or operator of an affected source demonstrates during performance testing that emissions of NO_x are less than 70 percent of the applicable standards in §60.44.

(2) HC&S has made the demonstration required under §60.45(b)(3) during numerous performance tests of Boiler 3 on both coal and fuel oil no. 2 (as well as on specification used oil) conducted since the source was first determined to be subject to Subpart D in 2001. Please see attached *Summary of Emissions Testing 2001-2011: Puunene Boiler 3* (Attachment 14).

(3) HDOH initially disagreed with HC&S' determination regarding the applicability of §60.45(b)(3) based on their contention that "the condition exempting facilities from this requirement if emissions testing demonstrates that emissions are less than 70 percent of the applicable standard is only good for the **initial** performance test for the equipment in question" (emphasis in original) and that, "due to the fact that the 180-day period after initial startup has passed, an initial performance test can no longer be done". However, in a 1995 Applicability Determination for two boilers operated by U.S. Steel in Fairfield, Alabama, EPA determined that performance tests could still be used to qualify for an exemption from the NO_x monitoring requirement so long as the required 30 day notification was provided prior to testing. The testing in question in the Alabama case had been conducted in January 1995 (albeit without the required 30-day notice). Since Subpart

[20] The provisions of §60.45(b)(3) appear to self-implementing; there is no requirement to request approval of this monitoring exemption from the Administrator. Nevertheless, HC&S is seeking concurrence from EPA and HDOH that its interpretation as to the applicability of this exemption is correct.

D would not apply to any boiler which commenced construction or modification after June 19, 1984 (the effective date of 40 CFR Part 60, Subpart Db), it is reasonable to conclude that the 1995 tests on the U.S. Steel boilers were also not conducted within 180 days of initial startup of the facilities. Thus, EPA has taken the position that testing conducted more than 180 days after initial startup of a source can still be used to demonstrate eligibility for the CEMS exemption. See U.S. EPA Applicability Determination Index Control Number 970006 (Attachment 15).

(4) Although §60.45(b)(3) does refer to the initial performance test with respect to delaying the installation of CEMS, the language of §60.45(b)(3) does not specify that **only** the initial performance test can be used to demonstrate that NOx emissions are less than 70 percent of the applicable standards: "If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in §60.44, a continuous monitoring system for measuring nitrogen oxide emissions is not required." In fact, earlier versions of the rule support the view that a source may rely on performance tests other than the initial test in order to qualify for the CEMS exemption. When originally promulgated in December 1971, Subpart D did not provide *any* exemptions from the requirement to install "an instrument for continuously monitoring and recording emissions of nitrogen oxides" (see §60.45(a)(3) at 36 FR 24879, dated December 23, 1971). Subpart D was subsequently modified to provide for the present exemption: "A continuous monitoring system for the measurement of nitrogen oxides emissions shall be installed, calibrated, maintained, and operated by the owner or operator except for any affected facility demonstrated during performance tests under §60.8 to emit nitrogen oxides pollutants at levels 30 percent or more below the applicable standards under §60.44 of this part" (see §60.45(c) at 40 FR 46256, dated October 6, 1975). It should be noted here that the exemption language does not even refer to "initial performance tests"; "tests under §60.8" at that time, as today, included both initial performance tests and "tests conducted at such other times as may be required by the Administrator". Other tests not specifically required by the Administrator, but conducted in accordance with the testing criteria specified in §60.8, should also be considered "tests under §60.8". Further indication of EPA's original intent with respect to the NOx monitoring exemption is provided in the preamble to the October 6, 1975 rule:

> *...the agency found that some situations may exist where the nitrogen oxides monitor is not necessary to insure proper operation and maintenance. The quantity of nitrogen oxides emitted from certain types of furnaces is considerably below the nitrogen oxides emission limitation. The low emission level is achieved through the design of the furnace and does not require specific operating procedures or maintenance on a continuous basis to keep the nitrogen oxides emissions below the applicable standard. Therefore, in this situation, a continuous emission monitoring system for nitrogen oxides is unnecessary. The regulations promulgated herein do not require continuous emission monitoring systems for nitrogen oxides on facilities whose emissions are 30 percent or more below the applicable standard.*

Similar discussion is found in the preamble of the October 6, 1975 rule promulgating requirements for emission monitoring under state implementation plans:

> *Also, certain types of boilers or burners, due to their design characteristics, may, on a regular basis attain emission levels of oxides of nitrogen well below the emission limitations of the applicable plan. The regulations have been revised to allow exemption from the requirements for installing emission monitoring and recording equipment for oxides of nitrogen when a facility is shown during performance tests to operate with oxides of nitrogen emission levels 30% or more below the emission limitation of the applicable plan. It should be noted that this provision applies solely to oxides of nitrogen emissions rather than other pollutant emissions, since oxides of nitrogen emissions are more directly related to boiler design characteristics than are other pollutants.*

The current language of §60.45(b)(3) was added to the rule in January 1977 (42 FR 5936, dated January 31, 1977) solely in order to clarify conflicting requirements for the installation of CEMS for NO_x under Subpart D. Prior to that amendment, §60.13(b) required that *all* continuous monitors "be installed and operational prior to conducting performance tests under §60.8", even through the requirement for installation was contingent upon the results of such tests. With this revision, EPA sought to clarify that installation of CEMS was not required until some reasonable time after testing was conducted. Clearly, EPA has historically recognized that, for some Subpart D sources, the installation of CEMS for monitoring of NO_x emissions is not necessary because NO_x emissions are well below the applicable limits based on the design of the boiler. Demonstration that emissions from a given boiler warrant such an exemption is to be made by stack testing. It is the results of the stack testing, not the timing of the tests, that should be used to determine whether a particular boiler qualifies for this exemption.

(5) Operation of a CEMS on a multi-fuel boiler which burns both fossil fuels and non-fossil fuels is inherently complex and is likely to lead to erroneous compliance determinations when a fuel of highly variable quality such as bagasse is being fired. This is in part due to the fact that, whereas the CEMS will measure emissions produced by *all* fuels being fired at any given time, only that portion of the measured emissions that is from firing fossil fuels (and wood residue) is subject to the Subpart D emission limits.[21] Further, only the heat input from firing fossil fuels (and wood residue) may be considered when determining compliance with emission limits in lb/MMBTU of heat input. This issue was previously addressed in the discussion of CEMS for monitoring SO_2 emissions above, but is of far greater significance with respect to emissions of NO_x because NO_x emissions rates from firing bagasse are far closer to those from firing coal (or fuel oil) than are emissions of SO_2. A more detailed discussion of the technical difficulties associated with using CEMS to monitor NOx emissions from a bagasse-fired boiler, including specific examples of the

[21] As previously noted, unlike emission limits in Subparts Da and Db which apply to emissions from *all* fuels being fired in an affected facility, all Subpart D emission limits are presented in terms of pounds of pollutant per million BTU of heat input ***derived from fossil fuel or fossil fuel and wood residue.***

extent of errors likely to be introduced into emissions calculations, was provided in our April 8, 2003 letter regarding CEMS requirements for Boiler 3 (Attachment 13) and therefore will not be repeated here. In summary, however, the use of a default "a-factor" during co-firing of bagasse with fossil fuels to estimate the portion of measured emissions resulting from combustion of bagasse will introduce significant errors into the estimation of emissions resulting from combustion of fossil fuel, principally resulting from the large variations in fuel quality that are typical of bagasse fuel.[22] HC&S remains deeply concerned that monitoring of NO_x emissions using a CEMS in accordance with Subpart D will result in frequent, inaccurate indications of noncompliance with emission limits under §60.44 when firing fossil fuels in combination with bagasse. For Boiler 3, a CEMS would not be a reliable method of determining compliance with Subpart D emission limits during periods of co-firing with non-fossil fuels, and this firing configuration represents the primary operating mode for the Puunene Mill boilers.

(6) Under §60.13(i)(3), the Administrator may approve alternatives to any monitoring procedures or requirements of Part 60, including alternative monitoring requirements when installation of a continuous monitoring system specified by Part 60 would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases. When bagasse is co-fired with fossil fuels, the NO_x emissions present in the effluent gases as a result of bagasse combustion will interfere with the ability of the CEMS to provide accurate measurements of NOx emissions resulting from fossil fuel combustion. This is due to the inability to accurately determine the portion of emissions measured by the CEMS that resulted from bagasse combustion, as described above. Thus, even if EPA determines that Boiler 3 is not eligible for the CEMS exemption under §60.45(b)(3) due to the timing of stack testing, EPA may still approve alternative monitoring of NO_x under §60.13(i)(3). In that case, HC&S believes that EPA should approve as an alternative to CEMS an annual stack test to measure NO_x emissions from fossil fuel firing and an annual boiler tune-up. EPA has previously approved this alternative to a NO_x CEMS for a fossil-fuel and bark fired boiler at a kraft pulp mill which fired primarily biomass fuel and which slightly exceeded the threshold that would have justified an monitoring exemption under the provisions of §60.45(b)(3). See U.S. EPA Applicability Determination Index Control Number 0500093 (Attachment 5).

---

[22] In order that emission rates measured by a CEMS during co-firing of bagasse with fossil fuels may be used to determine the emission rate from fossil fuel firing for the purpose of assessing compliance with Subpart D emission limits, the CEMS must be programmed with an "a-factor" that is based on the "best achievable emission level" for the fuel at "optimal conditions". In past stack test results, NO_x emissions from Boiler 3 during coal firing have varied from a low of 0.16 lb/MMBTU to a high of 0.30 lb/MMBTU, nearly double the low end of the range. Moreover, since bagasse is burned in sugar mill boilers "as produced" in the mill and can vary widely in moisture content (and heat content), this fuel is rarely burned under "optimal conditions". As a result, emissions from bagasse firing predicted through the use of an "a-factor" are likely to frequently be lower than actual emissions. This can result in a significant over-estimation of the portion of emissions measured by the CEMS that are attributable to fossil-fuel firing, and a corresponding error in compliance determinations made by the CEMS.

HC&S believes that the arguments presented above and in its prior submissions to EPA and to HDOH provide a strong justification for approval of alternative monitoring of opacity in lieu of installation of a COMS, of alternative monitoring of sulfur dioxide emissions in lieu of a CEMS, and of an exemption from the requirement to install a CEMS to monitor emission of nitrogen oxides. We appreciate the willingness of EPA and HDOH to continue to work towards a mutually acceptable compliance strategy for Boiler 3 at the Puunene Mill, and respectfully request that EPA approve of and/or concur with each of the proposed strategies for complying with emissions and fuel monitoring requirements under §60.45.

Should you have any questions or require further information in order to complete your evaluation of our requests, please do not hesitate to call me at (808) 877-2959 or Gary Rubenstein of Sierra Research at (916) 273-5126.

Sincerely,

Sean M. O'Keefe
Director, Environmental Affairs
Alexander & Baldwin, Inc.
For its division, Hawaiian Commercial and Sugar Company

<u>Attachments</u>

Attachment 1	Chronology of Events Pertaining to Puunene Mill Boiler 3 Compliance with New Source Performance Standards Under 40 CFR Part 60, Subpart D
Attachment 2	Request for Approval of Alternative Monitoring of Opacity Under NSPS Subpart D (letter to Director, Air Division EPA Region 9 dated March 8, 2002)
Attachment 3	Current Procedure for Meeting Alternative Opacity Monitoring, Notification, and Recordkeeping Requirements – Puunene Mill Boiler 3 (dated August 1, 2011)
Attachment 4	U.S. EPA Applicability Determination Index Control Number 0000010 (see Attachment 2)
Attachment 5	U.S. EPA Applicability Determination Index Control Number 0500093
Attachment 6	Request for Approval of Alternatives to Continuous Emissions Monitoring Requirements (letter to Manager, Clean Air Branch HDOH with copy to Director, Air Division EPA Region 9 dated April 8, 2003) – includes proposed fuel sampling and analysis procedures for fuel oil and coal
Attachment 7	HDOH Request for Determination (letter to Director, Air Division EPA Region 9 dated February 10, 2004)
Attachment 8	Updated Proposed Fuel Sampling and Analysis Procedures – Fuel Oil (Rev. September 2007)
Attachment 9	Updated Proposed Fuel Sampling and Analysis Procedures – Coal (Rev. July 2005)
Attachment 10	U.S. EPA Applicability Determination Index Control Number 9600010 (see Attachment 6)

Attachment 11	U.S. EPA Applicability Determination Index Control Numbers NR35 (see Attachment 6)
Attachment 12	U.S. EPA Applicability Determination Index Control Numbers 9800058
Attachment 13	Additional Information Regarding Boiler 3 CEMS (fax to Chief, Clean Air Branch HDOH, dated October 25, 2004)
Attachment 14	Summary of Emissions Test Results 2001-2011: Puunene Boiler 3
Attachment 15	U.S. EPA Applicability Determination Index Control Number 970006 (see Attachment 6)
Attachment 16	U.S. EPA Applicability Determination Index Control Number D100 (stating EPA's position that waste lubricating oils are not fossil fuels as defined in 40 CFR Section 60.41(b))

cc w/attachments:

Nolan Hirai, Acting Chief, HDOH Clean Air Branch
Gary Rubenstein, Sierra Research
Rick Volner, Jr., HC&S
Anna Skrobecki, HC&S
Nelson Chun, A&B